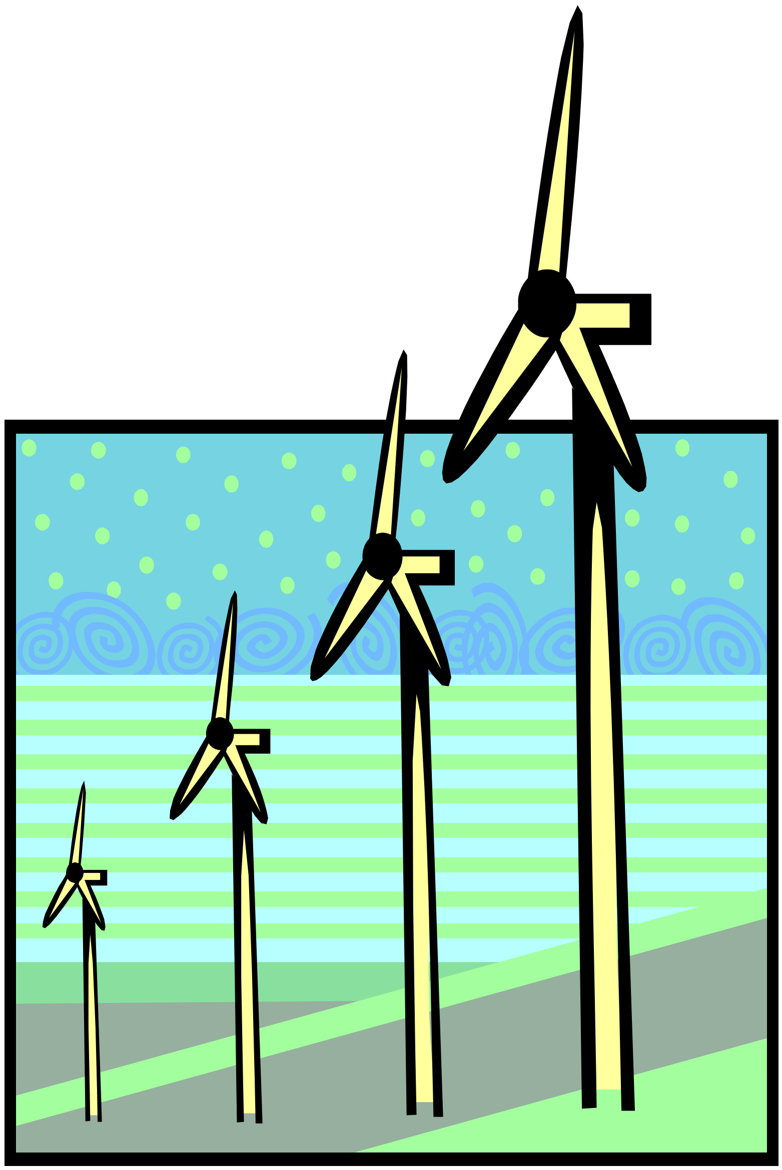
Attachment H
Transmission Reliability Assessment (2004 – 2008)

DRAFT – INTERNAL SMUD PURPOSES ONLY

SACRAMENTO MUNICIPAL UTILITY DISTRICT

Transmission Reliability Assessment

2004 - 2008



Power System Assessments
System Operations and Reliability **January 2004**

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Introduction

This ***Transmission Reliability Assessment*** concentrates on transmission issues the District is anticipated to encounter in advance of the Cosumnes Power Plant (CPP), and in the long-term as Sacramento area load grows. This report:

- Describes short-term actions necessary to meet peak loads before CPP is available,
- Outlines the technical feasibility and benefits of available alternatives necessary to meet the District's projected longer term load growth,
- Contains technical results that are intended to aid in the consideration of economic, contractual, political, and other factors influencing policy decisions.
- Meets the WECC/NERC Planning Standards for System Adequacy and Security[1], Category A, B, and C.

Power System Assessments (PSA) found the need to expand its analyses regarding load-serving capability (LSC) to include other factors that influence the ability to serve load. For internal discussion purposes, this report includes consideration of other aspects including:

- Resource adequacy due to transmission constraints
- New firm use (NFU) scheduling ability and California Independent Operator (CAISO) congestion management practices
- Simultaneous import capability N-2 limits

➢ It is important to recognize and understand there are technical and operational differences between:

  - **Load Serving Capability (LSC)** values based upon withstanding the worst single (N-1) outage and
  - **Total Resources** (generation plus import capability) available to meet load and reserve requirements.

Load Serving Capability

The LSC concept is a robust guideline PSA uses to ensure adequate infrastructure exists such that no single contingency results in a criteria violation. This LSC concept ensures that margin is built into the system while simultaneously meeting NERC/WECC Category B reliability criteria, as the District's transmission system is required to withstand the most severe single contingency during the extreme forecasted peak load. The LSC amount is compared to the District's extreme

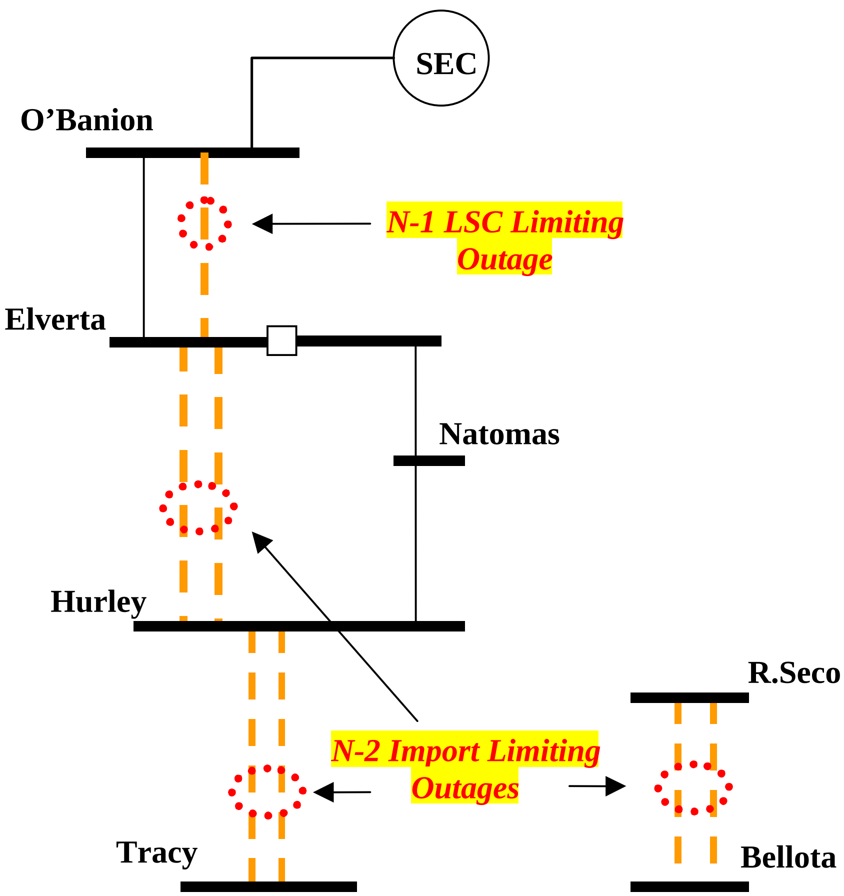
[1] *Assessments shall be conducted annually and shall cover critical system conditions and study years deemed appropriate by the responsible entity. They shall also be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons.*

weather load forecast. This is a reasonable comparison because the study cases used to determine LSC include the required reserve levels. This measure has historically been the most constraining element dictating the maximum load that could be reliably served.

Total Resources / Other Factors

Another measure of the District's ability to meet load is to simply stack up SMUD's resources, internal generation and import capability. This total is then compared to the load forecast plus reserve requirement. Control area import capability limits are governed by nomograms based upon NERC/WECC Category C reliability criteria. In particular, the District must prevent voltage instability and thermal overloads following any double line outage. Planned/controlled load shedding is permitted in order to maintain the overall security of the interconnected transmission system. The District has utilized a load-shedding scheme to meet these requirements in the past. PSA is concerned that absent necessary transmission upgrades, the MW amount of post-contingency load shedding and number of contingencies requiring such action will increase.

The diagram below illustrates the locations of the limiting outages associated with the single contingency LSC and the double contingency import limits. Operating nomograms protect against all three double line outages.



Executive Summary

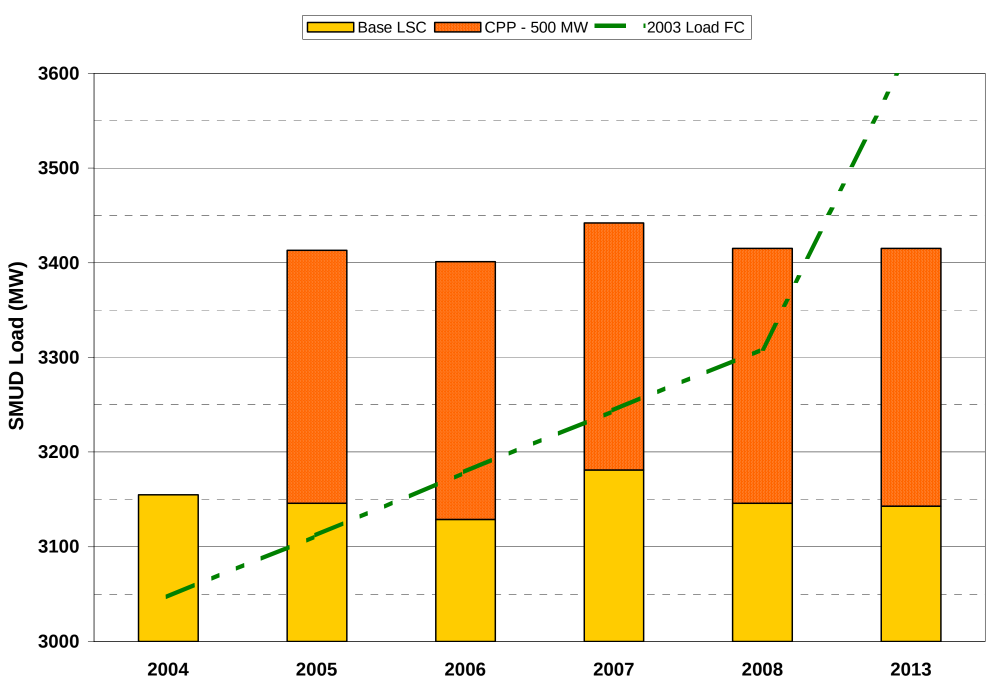
The District is facing challenges to meet the extreme weather load forecasts until the CPP is available. Load forecasts are higher due to increased customer growth and greater customer response to summer temperatures in 2003. Over the next couple of summers, the District may have to employ operational actions such as running the peakers more often, arming the direct load tripping scheme, or using ACLM to meet peak load. CPP provides some relief in 2005, but the District may face shortages in the 2008-09 timeframe without transmission system additions.

The District's LSC is limited to 3150 MW by the Elverta -O'Banion 230kV line outage and subsequent RAS tripping of Sutter Energy Center (SEC). Even after the addition of CPP in 2005, this outage remains the most severe single contingency. Furthermore, the CPP addition does not increase the District's ability to import additional power because it mitigates only one of three potential double outage limitations.

PSA's preferred alternative, a new double circuit 230kV line from SEC to Elverta, removes the Elverta – O'Banion outage as the single most severe outage and increases import capability by eliminating the Elverta – Hurley double line outage as a nomogram restriction.

The cost estimate for this project is $50 million. Due to long lead times, a commitment to construct additional facilities must be started now to meet future load growth. If started now, the project would be available in the post 2008 timeframe when the District forecasts potential load-serving and resource deficiencies.

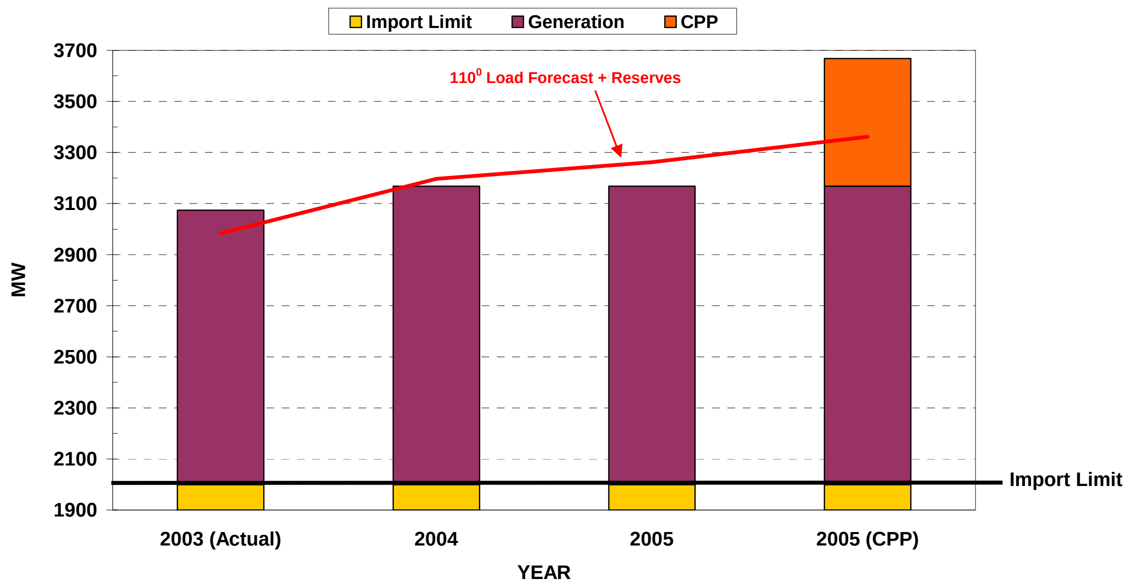
CPP Phase 1 - Load Serving Capability



Even though the District's transmission system presently has a LSC of approximately 3150 MW, this LSC definition is N-1 reliability based-it describes the surrounding transmission system's physical ability to serve load under the ***single*** most severe outage without incurring reliability criteria violations. In simpler terms, the District could meet a load demand of 3150 MW before a reliability violation would occur following a single contingency. However, this LSC definition does not account for import limits or scheduling constraints imposed by the CAISO, which could be more limiting in 2004 and 2005.

A more complete picture examines the District's total resources versus peak load forecast plus reserve requirements. To simply illustrate the challenges being faced to meet the extreme peak load over the next couple years, the District's total ability to generate and import power is compared to the load forecast plus reserves in the figure below.

Load Forecast and Resources 2003- 2005



NOTE: 2003 generation resources reflect the unavailability of Robb's Peak, Jones Fork, and McClellan units.

For planning purposes, the import limit shown above is considered a firm limit of 2000 MW. PSA does not consider load dropping as an acceptable planning mitigation strategy to increasing the District's import capability. Operationally, the District may have to arm load to be dropped post-contingency in order to meet extreme loads prior to the completion of CPP.

In addition to reaching simultaneous nomogram limits, fictitious "congestion" may limit the District's ability to ***schedule*** power through the CAISO's control area without incurring congestion charges. For example, if one of the R.Seco – Bellota lines is out of service, no real system problems occur, but load may have to be curtailed to stay within the schedule cuts imposed by the CAISO. This scheduling/congestion issue is described in detail on page 8.

While scheduling limits on the PG&E/CAISO system have become a near-term concern, WAPA increased some of its nearby facilities' thermal ratings in May 2003. It is important to note that WAPA changed the ambient temperature and wind speed assumptions only; <u>no physical upgrades were made to the conductor</u>. WAPA's ratings increases have eliminated most of the thermal limitations that constrained the District's LSC in previous years. In 2002, the outage of Elverta – O'Banion and RAS dropping of SEC overloaded WAPA's Tracy – Hurley 230kV lines. This year, that thermal constraint has been removed by means of higher ratings. The next reliability limit (voltage instability) is only slightly greater, resulting in slight increases to the District's LSC. The primary benefit from the WAPA ratings increase is operational in nature. The establishment of an emergency rating allows the operators time to make post-contingency system adjustments. A complete listing of WAPA's uprated facilities is located in the Appendix.

An additional topic covered in this year's report is a resource adequacy discussion describing the District's planning reserve methodology. The District uses its own unique approach to resource adequacy; the planning reserve level for the District was 11.3% in 2003 increasing to 14.9% by 2005.

The City of Roseville has plans to construct new generation, a 160 MW plant called the Roseville Energy Park (REP), scheduled for completion in 2006. REP will provide much needed voltage support in the growing Roseville area. <u>But REP also adversely affects the District's ability to import power by increasing the power flow into the already heavily loaded Elverta station</u>.

In northern California, Metcalf Energy Center (MEC) is the only major (>300 MW) generation plant (outside CPP) showing any construction activity. For this study, MEC was modeled as on-line beginning in 2007.

PSA also recommends installation of shunt reactors to provide mitigation of high voltage on the UARP buses.

A separate **Appendix** contains the background information useful to this year's study, including the load forecasts, PV curves, RAS descriptions and power flow diagrams for each study scenario.

Recommendations

Before Cosumnes Power Plant

In 2004-05, the District's options to meet peak load may include:

- Running the peakers more often,
- Arming the DLT scheme to increase import capability,
- Using ACLM as a reserve component (non-spin) or to reduce extreme weather peak loads,
- Active participation in the Sacramento Valley Study Group (SVSG) to determine maximum import capability is based on physical limitations described thoroughly in operating procedures, not fictitious congestion management practices.

Cosumnes Power Plant – 500 MW

This report reiterates the vital technical need to complete the first 500 MW as soon as possible. CPP provides local reactive support and directly reduces imports into the control area, particularly on the Rancho Seco – Bellota lines. Thus, CPP eliminates this N-2 as a nomogram constraint. Phase 1 of CPP also eliminates the need for the existing RAS opening Procter – Hurley for overloads on the Procter – Hedge line.

<u>CPP does not eliminate the SEC RAS or prevent plant tripping</u>. It allows SEC to generate at its full rated output, 525 MW. The initial 500 MW from CPP increases SMUD's total resources to 3675 MW (1675 MW generation and 2000 MW import capability). However, the LSC increases only 275 MW to 3400 MW. Due to its location, CPP cannot eliminate the most severe single contingency, the Elverta – O'Banion outage and subsequent RAS tripping of SEC.

Cosumnes Power Plant – 1000 MW – 2009 Option

Absent upgrades to mitigate the north of Elverta transmission issues, PSA does not recommend the completion of CPP Phase 2 (1000 MW). It provides a smaller increase of approximately 150 MW in LSC because it is not electrically situated to mitigate the voltage limits north of Elverta arising from the Elverta – O'Banion outage. The District will not be able to receive the full benefits from CPP until the north of Elverta transmission issues are resolved.

Two 230kV transmission line alternatives stand out as providing significant benefits:

- A new double circuit 230kV transmission line from Calpine's Sutter Energy Center to the SMUD side of the Elverta substation.

- A new 230kV line connecting the District's transmission system to WAPA's Tracy station provides reliability and strategic benefits. This alternative provides a physical connection to the Tracy "hub" and the potential cost savings by eliminating CAISO fees associated with COTP deliveries.

Sutter – Elverta Line – 2009 Option

The Sutter – Elverta line addresses the weakest point on the grid that directly impacts SMUD. It eliminates both the most severe single outage, the Elverta – O'Banion line with subsequent SEC plant tripping and a double line outage, both Elverta – Hurley lines. Although these facilities are not owned or operated by SMUD, this outage limits SMUD's LSC and import capability. This line would benefit SMUD in numerous ways:

- Adds 250 MW of LSC
- Allows the District to get the full voltage support benefits from CPP
- Cost sharing opportunity with WAPA, Roseville and Calpine
- Reduces Elverta bus-tie loading
- Adds operational simplicity
- Part of WAPA's Record of Decision related to Sacramento Area Voltage Support EIS
- Eliminates two most severe single contingencies: outage of Elverta-O'Banion with RAS tripping of SEC and outage of SEC – O'Banion, the radial tie to the generation plant
- Improves VAR exchanges with WAPA
- Mitigates N-2 Import Limit
- Provides additional time to pursue CPP Phase II Project
- Eliminates RAS on SEC

Based upon a December 2003 cost estimate performed by District staff, the Sutter – Elverta line cost is approximately $50 million. Calpine has expressed an interest in beginning environmental studies in Spring 2004 at their expense.

Alternatives Discussion Matrix

Alternative	Capital Cost	LSC Increase	Pros	Cons
Construct new double circuit 230kV line from SEC to Elverta	**$50 M**	**250 MW**	Eliminates both N-1 LSC and N-2 Import, Improves MVAR exchange, Operational simplicity	Most expensive, requires multiple party coordination
Construct new single circuit 230kV line from SEC to Elverta	**$48 M**	**200 MW**	Slightly less expensive than double circuit alternative.	Smaller LSC increase
Swap O'Banion line(s) to SMUD side of Elverta	**<$5 M**	**0 MW**	Reduces flow across Elverta tiebreaker	Band-aid, does not address most severe single outage
Install 100 MVAR Shunt Caps at Elverta	**$5 M**	**100 MW**	Less expensive, No public opposition	Does not address thermal overloads or import limits
Pursue through WECC as (un)allowable effect on other system	**$0**	**0 MW**	Places mitigation responsibility on appropriate entities	Likely time consuming with no guarantee that necessary facilities will be built
Do Nothing	**$0**	**0 MW**	No capital cost	Inability to reliably serve load

NOTE: The first two alternatives have an opportunity for cost sharing between SMUD, Roseville, Calpine, and WAPA.

Tracy– Elk Grove Line – Beyond 2008 Option

The Tracy – Elk Grove 230kV project would link the District's Elk Grove substation to WAPA's Tracy substation. PSA examined several alternatives in detail for interconnection at Tracy[2]. This would be a cooperative effort with WAPA as construction would entail rebuilding one of the existing structures containing one of the Tracy – Hurley lines as a double circuit with both Tracy – Hurley lines and cutting over the remaining Tracy – Hurley line to Tracy – Elk Grove. It is imperative that a contractual agreement with WAPA be reached on ownership and transmission rights prior to initiation of this project.

This lines has the following benefits:

- Increases LSC by 125 MW
- Physical path to COTP
- Adds operational simplicity
- Part of WAPA's Record of Decision related to Sacramento Area Voltage Support EIS

The estimated cost for this project is $35 - $40 million.

230kV line to WAPA's Tracy Station

The preferred alternative would construct a double circuit tower that would contain both WAPA Tracy – Hurley 230kV lines. The remaining Tracy – Hurley line would be cutover and terminated at SMUD's Elk Grove station. This would be a cooperative effort with WAPA.

This project is more cost effective if the existing WAPA right-of-way is utilized without having to obtain additional land.

NOTE: WAPA has initiated a process to further uprate the existing Tracy – Hurley 230kV lines. Obviously, the benefit depends on the amount of increased capacity resulting from the rerated facilities. PSA is coordinating this effort with WAPA and expects a decision by summer 2004.

[2] See memo PSA 01-009 dated 8/15/01 for additional Tracy interconnection details.

Transmission Scheduling Discussion

Background

Following the SMUD control area formation, the CAISO created two new branch groups on which CAISO congestion management is applied[3]. SMUD's control area interconnection points with WAPA and PG&E became the Elverta/Hurley and Ranch/Lake branch groups, respectively. These branch groups are tied to two new congestion zones, SMDE & SMDW. SMUD's control area scheduling limits were negotiated to be the sum of the individual lines' thermal ratings comprising the branch group as tabulated below. Each of these branch group's ratings includes SMUD's ETC allocation.

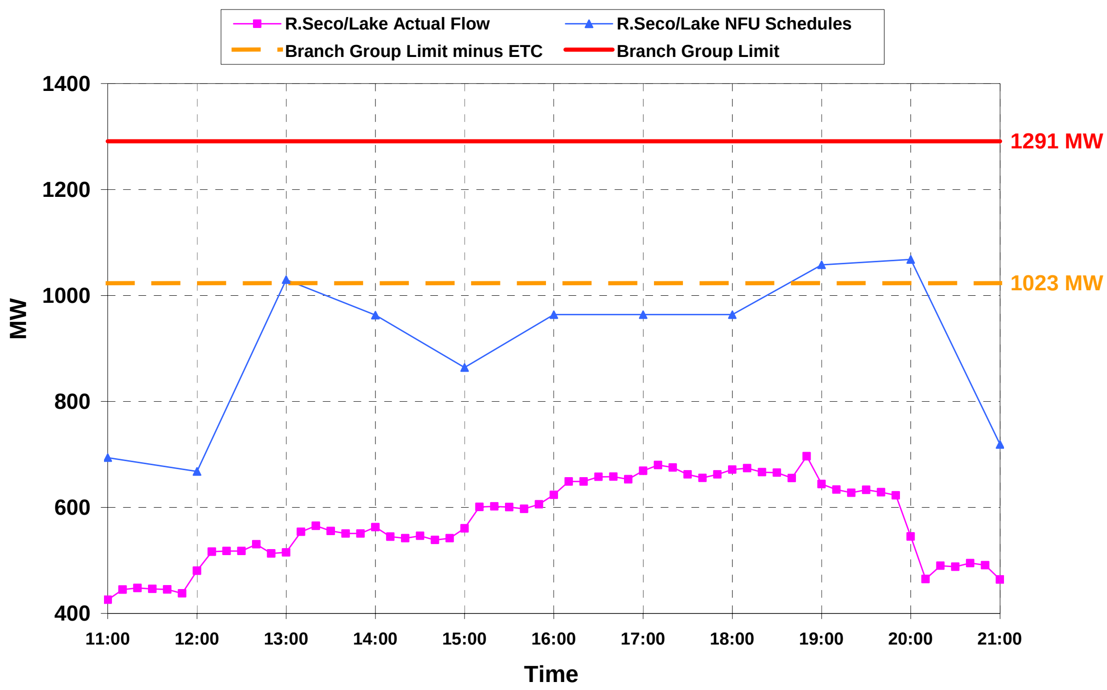
CAISO BRANCH GROUP	*BRANCHES*	*RATING*
ELVERTA/HURLEY[4] (SMDW)	Elverta Breaker 1182	797 MW
	Elverta – Hurley #1	396 MW
	Elverta – Hurley #2	435 MW
	Tracy – Hurley #1	396 MW
	Tracy – Hurley #2	435 MW
	Total	***2459 MW***
RANCHO SECO/LAKE (SMDE)	Lake – Gold Hill	303 MW
	Rancho Seco – Bellota #1	494 MW
	Rancho Seco – Bellota #2	494 MW
	Total	***1291 MW***

Subtracting the 268 MW (EHV, Solano Wind, Slab Creek, SOTP) of ETCs from the SMDE branch group leaves 1023 MW of NFU scheduling capability. During the hot summer days of July 2003, SMUD schedulers were approaching these scheduling limits and during three hours (13,19-20), SMUD's HA schedules actually exceeded the NFU availability of 1023 MW.

In theory, the District would pay congestion charges for each "overscheduled" MW. In the above case, SMUD, CAISO, and PG&E reached an agreement to waive all charges related to congestion management.

[3] The CAISO congestion management model can only determine when DA or HA schedules exceed the branch group rating-it is a poor predictor of real-time overloads.
[4] Reflects WAPA's May 2003 thermal rating increases.

July 18, 2003 Interzonal Congestion on R.Seco / Lake Branch Group



Derate of NFU Scheduling Capability

Other factors aggravating this issue include any COTP derates and WAPA's resistance to providing additional transmission. The latter issue is likely tied to WAPA's reluctance to allow RAS operation at the Sutter Energy Center. In other words, after SMUD schedulers have fully utilized NFU capability at R.Seco/Lake, they may request additional transmission from WAPA to help meet load. However, WAPA has denied transmission in some cases. It is PSA's belief that WAPA does not want to see the SEC RAS activate as it demonstrates WAPA's transmission system may be oversold north of Elverta. The figure above shows the actual flows on the R.Seco/Lake branch group were well below the 1291 MW branch group thermal limit.

An even greater shortage could arise under contingency conditions. The CAISO reduces the scheduling limit by subtracting the amount of the outaged line thermal limit from 1291 MW. For example, if one of the R.Seco – Bellota lines is out of service for any reason, the resulting NFU branch group scheduling limit becomes 1291 - 494 = 797 MW where 494 is the thermal rating for one of the R.Seco – Bellota lines.

Alternative Solutions

1. Self-impose a scheduling limit of 1023 MW on the SMDE branch group.

2. Run the Procter, Carson Ice, and McClellan peakers when SMUD load exceeds 2800 MW.
3. Pursue the ability to submit very low adjustment bids (i.e. $.01/MW) to limit exposure to congestion costs.
4. Convince the CAISO to "ignore" congestion on this branch group due to several factors: a flawed congestion management system, SMUD (APX) is the only scheduling coordinator using R.Seco/Lake, actual flows on the lines are well below the scheduling and/or thermal limits, and stable operation is governed by nomogram limits at all times.

Resource Adequacy / Planning Reserve

Background

Historically, the utility industry has implemented reserve procurement policies that limited reliability risk and ensured compliance with WECC operating reserve and NERC regulation control performance criteria.[5] However, the added complexity associated with energy markets and the crisis of 2000 – 2001 prompted a review of the implementation and framework of resource adequacy and planning reserve issues.

Currently, the common thinking is that future resource adequacy requirements may also:

- Restore the obligation to serve
- Encourage future investment in electric infrastructure
- Support reliable system operations
- Mitigate market power

District's Planning Reserve Methodology

SMUD's planning reserve is determined differently than simply summing the percentages of forced outage rates, generation derates, and operating reserves. In short, SMUD uses a five-year horizon to ensure there are adequate resources to meet the 1 in 10 peak load forecast on an 110^{o} F day while withstanding the most severe single contingency.

The following calculation illustrates this methodology and develops a percentage reserve number for comparison purposes.

District Planning Reserve Calculation

SMUD's 2003 summer forecast for normal and adverse weather peak demand was 2711 MW and 2867 MW, respectively. Using the adverse weather forecast of 2867 MW, PSA analyzed the transmission system and identified alternatives so that no reliability violations occurred for any single contingency. In addition, SMUD's control area must maintain ~150 MW of (single largest contingency) operating reserve.

Assuming the baseline is the normal 1 in 2 demand forecast of 2711 MW, the District's planning reserve is calculated to be

$$\left[(2867 - 2711) + 150\right] \div 2711 * 100 = 11.3\%$$

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[5] Minimum Operating Reliability Criteria (MORC) dictates WECC control area regulating and contingency reserve requirements.

The 11.3% reserve percentage may be conservative because it does not account for the ability to withstand the most severe single contingency. PSA did not attempt to quantify this additional value because the LSC definition includes the ability to withstand the outage only, not the additional reserves necessary to readjust the system post-contingency, in preparation for the next contingency.

In 2005, with CPP on-line, SMUD's planning reserve will increase as shown below:

$$\left[(3112 - 2926) + 250\right] \div 2926 * 100 = 14.9\%$$

where 3112 is the extreme 1 in 10 load forecast, 2926 is the baseline load forecast, and 250 is the single largest contingency as described below.

Operating Reserve

Today, the District's Operating Reserve requirement is primarily driven by the single largest contingency of the 150 MW Campbell's Soup cogeneration plant. Beginning in 2005, the largest single outage will become one of the gas turbines at Cosumnes Power Plant. A trip of one gas turbine will cease its exhaust flow completely and reduce the steam making capability accordingly. This 50% reduction in steam flow reduces the steam turbine generator output by approximately one half resulting in a 250 MW single largest contingency. SMUD's control area will be required to carry 250 MW of spinning and non-spinning reserve whenever CPP is generating at full output.

Roseville Energy Park Impact

The City of Roseville has proposed a new generation project, the Roseville Energy Park (REP) that is currently under review by the California Energy Commission (CEC). The CEC estimates a decision in December 2004 with an on-line date in June 2006. This generation plant is electrically located to partially mitigate the District's most severe single contingency by providing voltage support closer to the Elverta/Natomas area.

<u>However, the REP increases flows across the Elverta tie-breaker such that the N-2 of both WAPA's Elverta – Hurley lines will overload Elverta breaker 1182. This latter thermal overload adversely affects the District's import capability.</u> This issue is being resolved through the SVSG and CEC processes.

Elverta Tie-Breaker 1182 Loading following the Elverta – Hurley 1 & 2 Double Outage

2006 Scenarios	Loading[6]
Base Case	2128 A
REP Addition	2399 A

The chart on page 16 demonstrates the LSC increase which does not consider the adverse impact on SMUD's import capability.

[6] The normal and emergency rating on the breaker is 2000 and 2240 amps, respectively.

Load Serving Capability (LSC) Figures

The District's LSC based upon the various alternatives considered compared to the most recent adverse peak weather forecast.

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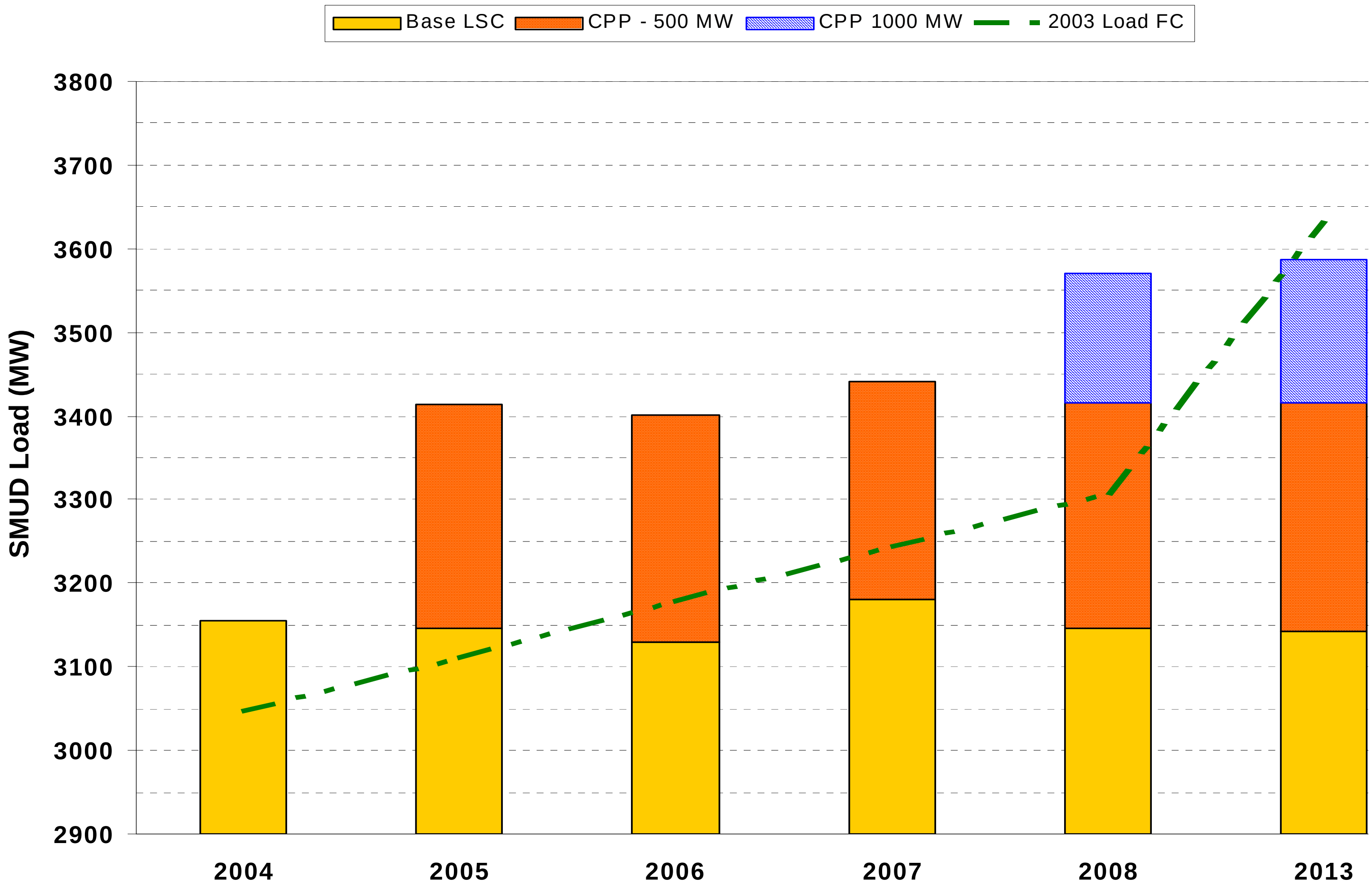
LSC with Cosumnes Power Plant



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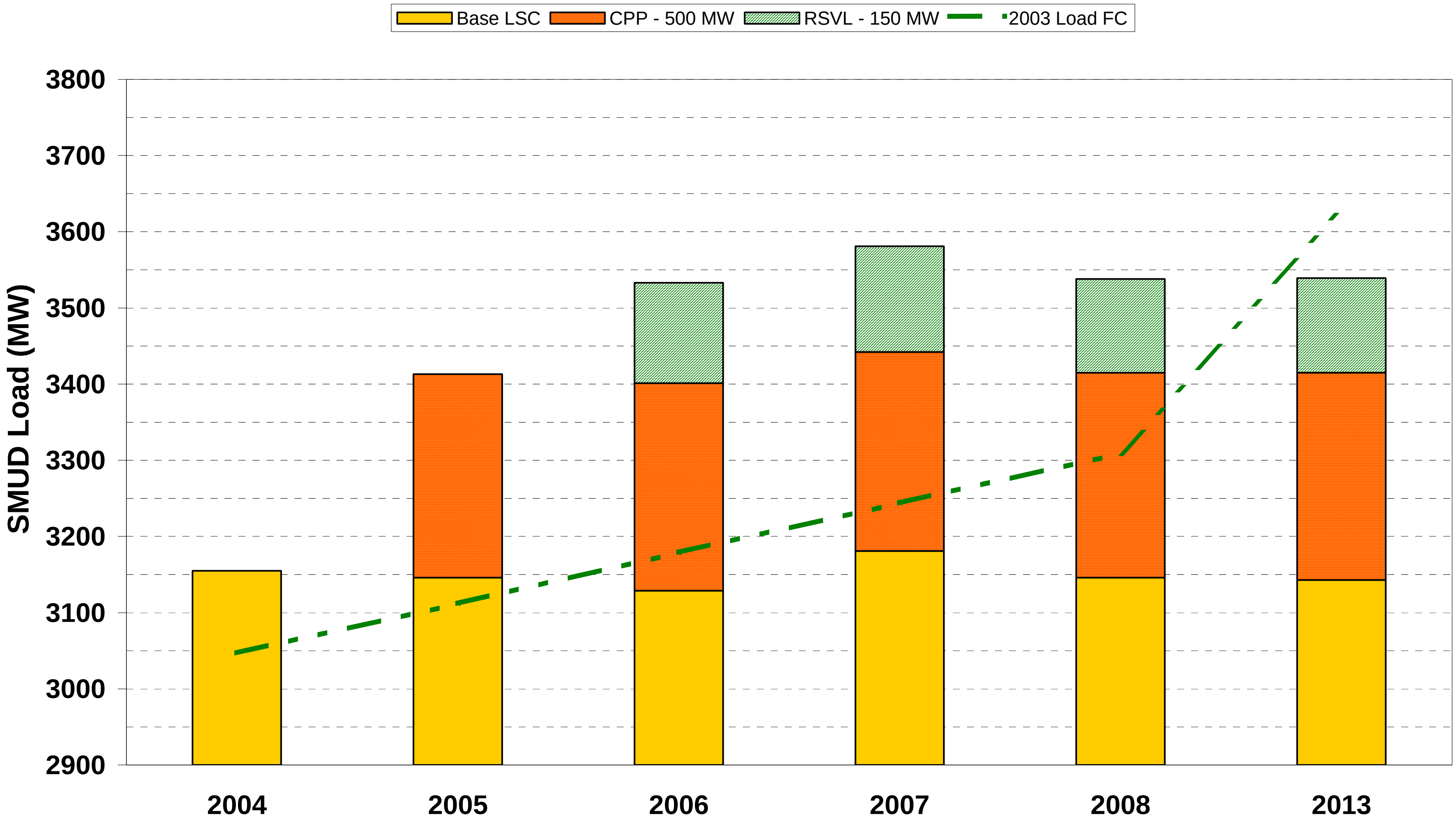
LSC with 150 MW Roseville Energy Park



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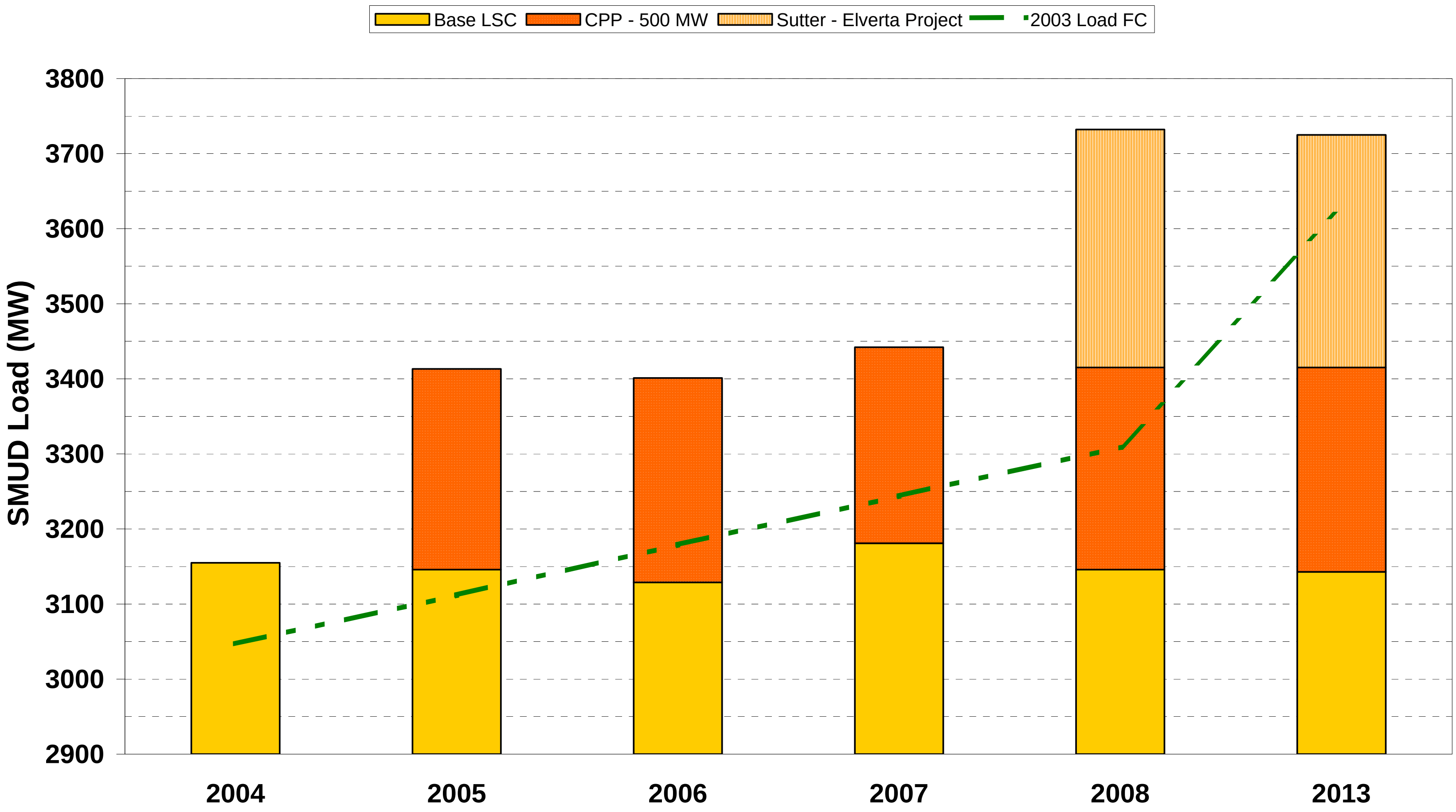
LSC with CPP 500 MW and Sutter – Elverta 230kV Line



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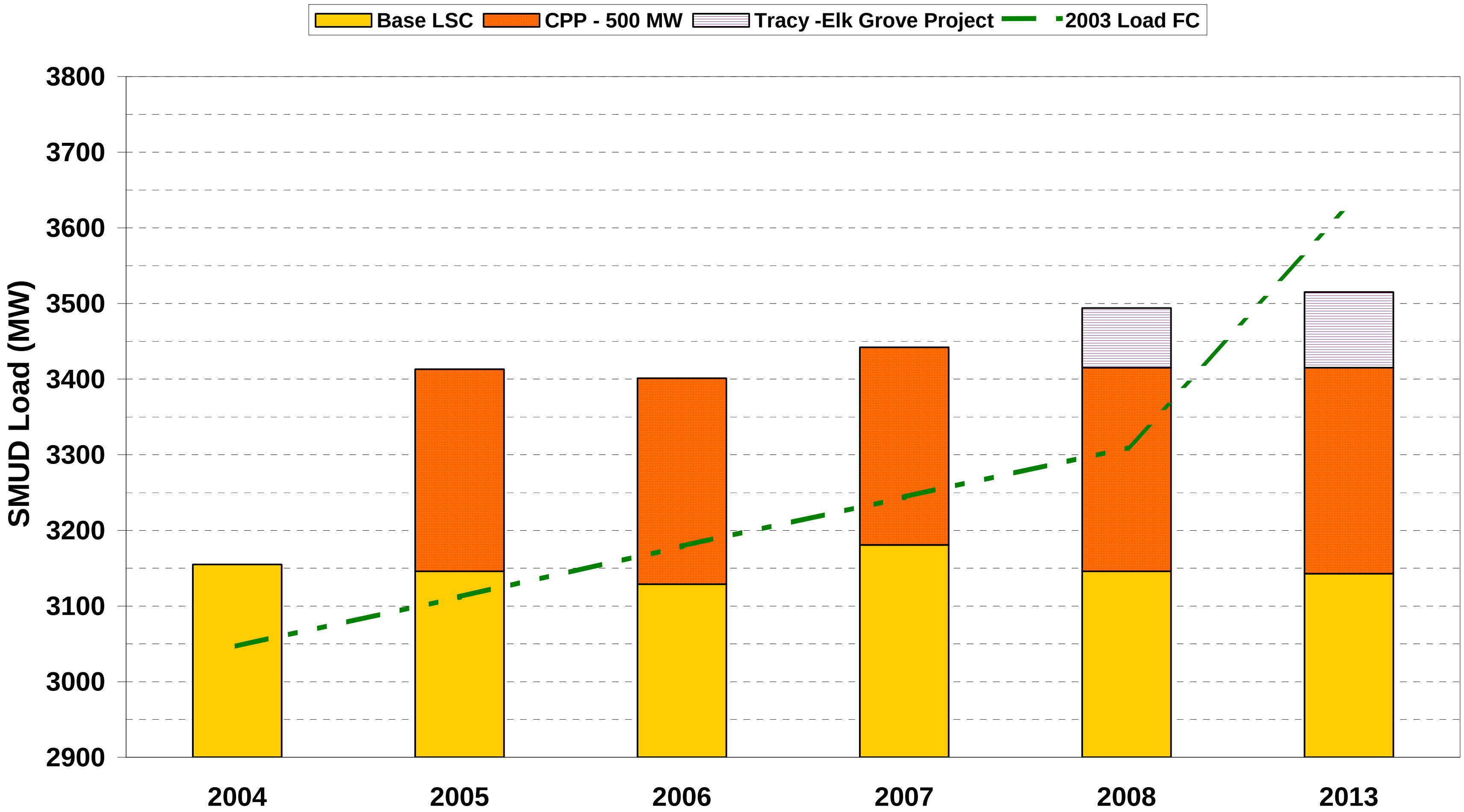
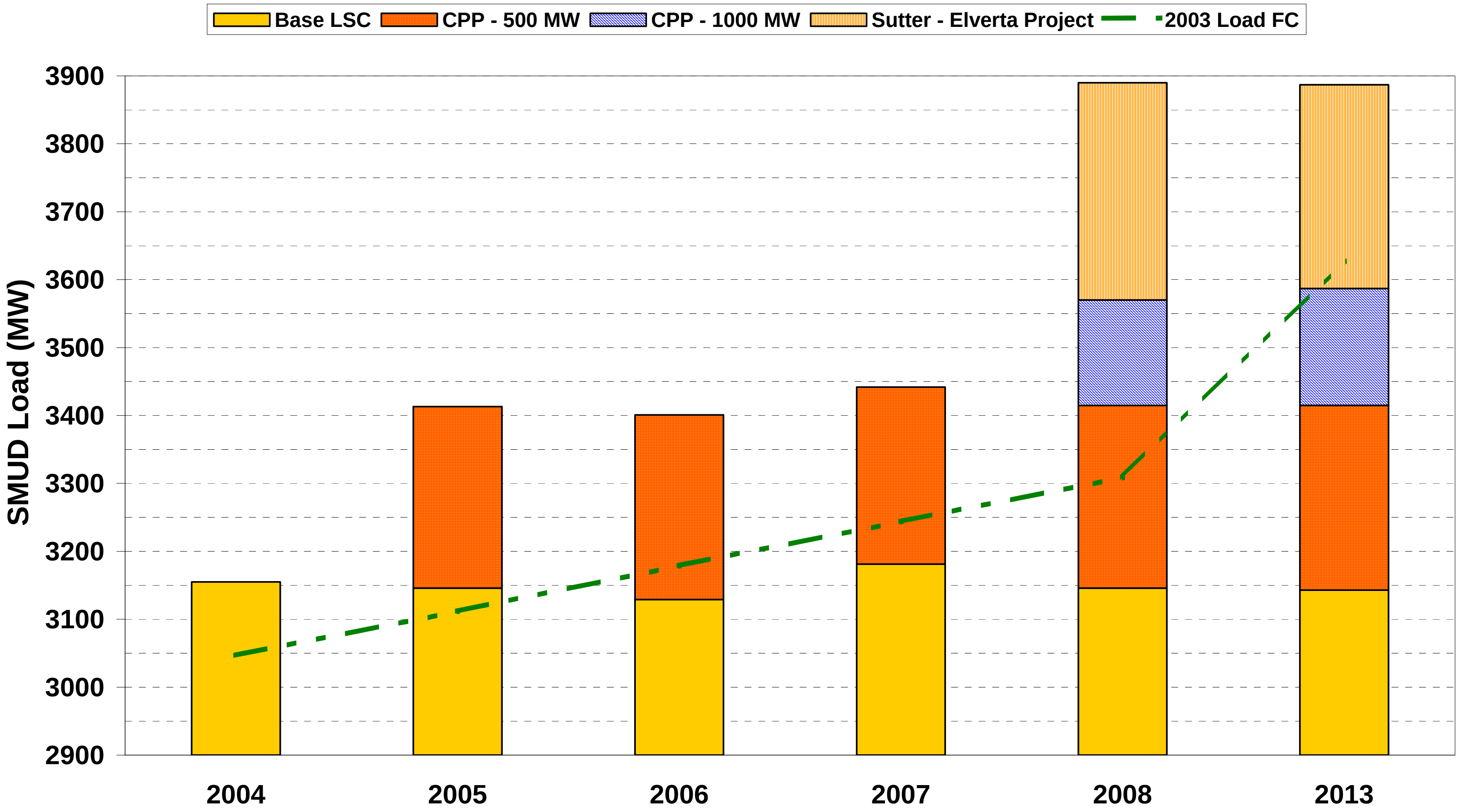
LSC with CPP 500 MW and Tracy – Elk Grove 230kV Line



LSC with CPP 1000 MW and Sutter – Elverta 230kV Line



Discussion of Other Projects

Iowa Hill Pumped Storage

The Iowa Hill pumped storage is currently being examined in the Hydro Relicensing process. This project would add operational and reliability flexibility to the District's Control Area including while increasing the LSC by 200 MW.

A more complete list of the attributes is being separately examined, and is mentioned here due to its incredible potential.

Static Compensators (Statcom)

Statcoms and shunt capacitors are options primarily when the system is voltage limited. Statcoms can also be configured and used in applications to redirect power away from the limiting thermal element, thereby allowing greater LSC caused by selective thermal limitations. New York uses them in this configuration. However, this is an expensive alternative and would only be recommended to if all other options have been exhausted.

Approximate Cost: $15-$20 million for an increase of 100 MW to SMUD's LSC.

Note: Statcoms do not increase import capability limits based on thermal overloads.

Shunt Capacitors

PSA meets with Distribution Services regularly to discuss additional capacitor requirements. Presently, the transmission target of .99 lag is being met through additions to the distribution system.

Shunt Reactors

Shunt reactors are applied to regulate the reactive power balance of a system by means of compensating for the surplus reactive power generation of transmission lines. Reactors are normally disconnected at heavy load and are connected at low load periods. In the spring and winter months, the district's loads are significantly lower than it's peak loads in the summer. The district's transmission system is built with the intention of providing a load serving capability that is adequate for peak load conditions. However, during low load conditions, the voltages rise above acceptable levels in some portions of the system. This instance is specifically true in the Upper American River Project (UARP). The UARP consists of four 230-kV buses located at Camino, Jaybird, Union Valley, and White Rock substations, and four 69-kV buses located at Jones Fork, Loon Lake, Robb's Peak, and Union Valley. Since the lines interconnecting these buses are fairly long, and some of the generating units may be operating during low load conditions, the voltages on the UARP buses rise up to 5% above their nominal voltage. Power flow studies were conducted to examine the optimum size and placement of a reactor to limit over voltages during these conditions.

Starting with a light spring base case, the District's loads, as well as, the loads in the surrounding central valley area were scaled to 60% of the peak loads to simulate the conditions under which high voltages have been observed on the District's system. The modeled district load under these conditions was 800 MW. The load outside the central valley was not scaled down since its effect on the bus voltages in the District is insignificant. The generation in the UARP was assumed to be running at approximately half of its maximum capacity, and the existing reactors at Pocket, Lake, and Hurley substations were turned on in each of the study cases. Eight cases modeling the placement of a reactor at each of the eight 230-kV and 69-kV buses were developed.

An examination of the data obtained from the eight base cases developed for this study, reveals that a 60 MVAr reactor sited at the Union Valley 230-kV bus would reduce the voltages on the UARP buses to acceptable levels (approximately 1.03 p.u.) without degrading the voltages on the rest of the District's system.

		No Reactor Modeled	**White Rock 230 kV**	**Jaybird 230 kV**	**Camino 230 kV**	**Union Valley 230 kV**	**Union Valley 69 kV**	**Jones Fork 69 kV**	**Loon Lake 69 kV**	**Robbs Peak 69 kV**
NAME	**kV**	**Per Unit Voltage**								
CAMINO S	230	1.0537	**1.0401**	**1.0407**	1.0366	1.0396	**1.0413**	**1.0416**	**1.0414**	**1.0415**
JAYBIRD	230	1.0534	1.0399	1.0352	1.0397	1.0376	1.0394	1.0398	1.0396	1.0396
UNIONVLY	230	1.0542	**1.0415**	1.0390	**1.0401**	1.0360	1.0385	1.0390	1.0387	1.0388
WHITEROK	230	1.0539	1.0376	**1.0408**	**1.0400**	**1.0400**	**1.0423**	**1.0426**	**1.0424**	**1.0425**
JONESFRK	69	1.0195	1.0102	1.0084	1.0092	1.0062	0.9749	0.9348	0.9756	0.976
LOON LK	69	1.0283	1.0238	1.0229	1.0233	1.0218	0.9983	1.0004	0.9420	0.9733
ROBBS PK	69	1.0230	1.0160	1.0146	1.0152	1.0129	0.9852	0.9873	0.9594	0.9432
UNIONVLY	69	1.0194	1.0101	1.0083	1.0091	1.0062	0.9748	0.9770	0.9755	0.9759

PSA is reviewing PI data for 2003 to verify the extent and causes of real-time high voltages experienced on the UARP system. PSA will subsequently issue a final recommendation.